NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date: XX/XX/2018

Region: Raleigh Regional Office
County: Durham
NC Facility ID: 3200375
Inspector's Name: Stanley Williams
Date of Last Inspection: 06/15/2018
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): MP Durham, LLC (Landfill Gas-to-Energy Project)

Facility Address:
MP Durham, LLC (Landfill Gas-to-Energy Project)
2115 East Club Boulevard
Durham, NC 27704

SIC: 4911 / Electric Services
NAICS: 221119 / Other Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 15A NCAC 02D .0516, 02D .0521, 02D .0524, 02D .1111, 02Q .0513
NSPS: Subpart JJJJ
NESHAP: Subpart ZZZZ
PSD: N/A
PSD Avoidance: N/A
NC Toxics: 15A NCAC 02Q .0702; DAQ model for formaldehyde
112(r): N/A
Other: State BACT (SB3), GS 62-133.8(g); Major Source of HAP under Title III

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Bo Donnelley Site Operator (860) 294-6132 2115 East Club Boulevard Durham, NC 27704	Steve Laliberty President (860) 678-7537 One Grove Street, 6th Floor New Britain, CT 06053	Steve Laliberty President (860) 678-7537 One Grove Street, 6th Floor New Britain, CT 06053

Application Data

Application Number: 3200375.18A
Date Received: 03/29/2018
Application Type: Renewal/Modification
Application Schedule: TV-Renewal

Existing Permit Data

Existing Permit Number: 09971/T03
Existing Permit Issue Date: 08/26/2015
Existing Permit Expiration Date: 09/30/2018

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2016	1.30	15.80	14.50	62.70	4.10	14.58	13.58 [Formaldehyde]
2015	1.60	27.00	1.10	84.00	4.50	1.23	0.7530 [Hydrogen chloride (hydrochlori]
2014	1.70	30.00	1.10	87.00	4.70	1.47	0.8075 [Hydrogen chloride (hydrochlori]
2013	1.80	25.00	1.20	93.00	4.80	1.59	0.8700 [Hydrogen chloride (hydrochlori]
2012	1.50	26.00	1.0000	96.00	5.00	1.33	0.7325 [Hydrogen chloride (hydrochlori]

Review Engineer: Joshua L. Harris

Review Engineer's Signature: **Date:**

Comments / Recommendations:
Issue 09971/T04
Permit Issue Date: XX/XX/2018
Permit Expiration Date: XX/XX/2023

1. Purpose of Application

MP Durham, LLC is a wholly owned subsidiary of Methane Power, Inc. This facility received its initial Air Permit on February 18, 2009 to construct and operate a landfill gas-to-energy facility in Durham, North Carolina. The city of Durham leases land to MP Durham, LLC and landfill gas will be collected at the Durham County Landfill and sent to this facility. The facility is requesting renewal of their current air permit, with a modification to reclassify as a major source of HAP under Title III.

Application No. 3200375.18A was received on March 29, 2018. While the renewal application was considered complete and was timely received, however the request for reclassification did not include the required application fee for a permit modification. The application fee for the modification to reclassify the facility was received on May 24, 2018. This application will go through the 30-day public notice and the 45-day EPA review periods.

The facility contact for this application is Steve Laliberty, President, (860-678-7537). A consultant, Smith Gardner Engineers, Inc., prepared the application. The contact at Smith Gardner is Mary Kennamer, Staff Engineer, (919-828-0577).

2. Facility Description

MP Durham, LLC is the owner of a landfill gas-to-energy (LFGTE) facility located adjacent to the Durham County Municipal Solid Waste (MSW) Landfill on land owned by Durham County. The facility is only associated with the Durham County MSW Landfill in that it receives its landfill gas (LFG) for fuel. The gas is comprised of roughly a 50/50 mixture of methane and carbon dioxide that is created from decomposition of MSW. The Durham County MSW Landfill extracts LFG through gas collection wells, then sends it to MP Durham, LLC, which operates a treatment system to remove moisture and some particulates. MP Durham, LLC uses this pre-treated/conditioned LFG to fuel two engine/electric power generators (gensets). The gensets are GE Jenbacher model 320 LFG-fired, 4-stroke, lean burn, spark ignition reciprocating internal combustion engines (RICE) (1468 horsepower-hp - output)/generators (1059 kilowatts - kW - output) with a maximum 9.796 mmBtu/hr (20,755 ft^3/hr gas firing rate - assuming fuel gas LHV is 472 Btu/ft^3). The two gensets would consume approximately 363.6 million ft^3 of LFG per year if they were operated continuously at full load.

The energy produced with these gensets is sold the local power company (Duke Energy Progress). Duke Energy Progress also purchases renewable energy certificates to help meet its regulatory renewable energy obligation established in the North Carolina Renewable Energy Portfolio Standard. A flare, owned and operated by the Durham County MSW Landfill, serves as a backup combustion device to burn any excess landfill gas.

3. Application Chronology

03/29/18 The Raleigh Regional Office (RRO) received the permit application, Application No. 3200375.18A, and forwarded copies to the Raleigh Central Office (RCO)

04/04/18 RCO received copies of the permit application from RRO. There was no request to keep any information confidential. The renewal application appeared to be complete, however there was no application fee included for the requested modification to reclassify the facility as a Title III Major source.

04/09/18 RCO sent the facility a letter acknowledging receipt of the permit application.

05/17/18 Joshua Harris sent an email to Mary Kennamer, Project Consultant, requesting that the $947 permit modification fee be submitted for the Title III application.

05/22/18 Joshua Harris sent an email to Mary Kennamer regarding toxics modeling for formaldehyde which exceeds its Toxic Permitting Emission Rate (TPER) under 15A NCAC 02Q .0711, and requested additional information for dispersion modeling. Mr. Harris stated that DAQ would perform the modeling, or that the facility may perform the modeling if they choose. Mr. Harris included a copy of the “D3 Form” for the information needed for DAQ to perform modeling.

05/24/18 RCO received the required permit modification application fee.

06/20/18 Joshua Harris sent Mary Kennamer an email regarding the status of the request for formaldehyde modeling information. Ms. Kennamer followed-up with a phone call, and submitted the requested information via email for DAQ to conduct dispersion modeling.

06/21/18 Joshua Harris sent Mary Kennamer an email requesting additional information necessary for DAQ to conduct dispersion modeling, specifically regarding heights of buildings near the facility.

06/21/18 Joshua Harris received an email from Matt Lamb, Senior Scientist, with the requested building heights for dispersion modeling.

07/18/18 Matt Porter, DAQ AQAB, completed the dispersion modeling analysis for formaldehyde.

07/24/18 Joshua Harris sent electronic copies of the permit and review documents to Booker Pullen, RCO, and Charles McEachern, RRO, for comments.

07/25/18 Booker Pullen commented that DAQ is allowing facilities to request that Senate Bill 3 BACT limits be changed to be equivalent to the NSPS Subpart JJJJ emission standards, and recommended that the facility be contacted regarding this potential change.

07/25/18 Joshua Harris sent an email to Steve Laliberty regarding the ability to change the Senate Bill 3 BACT limits to be equivalent to the NSPS Subpart JJJJ at his request. Mr. Laliberty responded and requested that these limits be set to reflect the NSPS Subpart JJJJ standards.

07/30/18 Joshua Harris sent electronic copies of the revised draft permit and review documents to Booker Pullen, RCO, and Charles McEachern, RRO, for comments. Neither Mr. Pullen nor Mr. McEachern had comments on the revised documents. RRO recommends issuance.

08/02/18 Joshua Harris sent electronic copies of the permit and review documents to Steve Laliberty and Mary Kennamer for comments.

08/09/18 Joshua Harris received an email from Matt Lamb with comments on the draft permit. Mr. Lamb's comments, and DAQ's responses are contained in Attachment 1.

08/10/18 Joshua Harris forwarded a copy of the facility's comments to the RRO.

08/10/18 Joshua Harris spoke with Matt Lamb regarding the comments received, and asked about the status of ES-EG3. Mr. Lamb stated that the engine is no longer on site and that there aren't currently any plans to repair or replace the engine after it was damaged. Mr. Harris sent an email to Steve Laliberty, requesting that he confirm that he would like ES-EG3 removed from the permit. Mr. Laliberty responded, confirming the request to have ES-EG3 removed.

08/14/18 Joshua Harris spoke with Matt Lamb and discussed DAQ's responses to the comments he submitted. Mr. Harris followed up with an email containing the responses and revised permit and review documents.

08/15/18 Joshua Harris received an email from Matt Lamb indicating that there were no additional comments.

Xx/xx/18 30-day public notice and 45-day EPA review periods begin.

Xx/xx/18 Public notice period ends.

Xx/xx/18 EPA review period ends.

Xx/xx/18 Air Quality Permit Revision No. 09971T04 issued.

4. Table of Changes to Existing Permit No. 09971T03

Page No(s).	Section	Description of Changes
Cover and Throughout	Cover and Throughout	• Updated letterhead and DEQ logos. • Updated application/permit numbers. • Updated dates. • Updated Mailing Address. • Updated permit conditions to most recent permitting language. • Formatted throughout. • Updated cross-references throughout. • Removed references to ES-EG3 throughout.
3	Emission Sources Table	• Removed ES-EG3 as an emission source. • Specified subparts ZZZZ and JJJJ, respectively, for MACT and NSPS applicability.
4	2.1 (Table)	• Reorganized table to show standards in the same order in which they appear in the permit. • Updated State BACT limits for all engines to equal the NSPS Subpart JJJJ emission standards for NOx and CO, and the burning of landfill gas for PM_{10}/$PM_{2.5}$.
5	2.1. A.2.	Added 15A NCAC 02D .0521, “Control of Visible Emissions” condition.
5	2.1. A.3.d.	Revised the New Source Performance Standard (NSPS) testing requirements.
6	2.1. A.4.a.	Revised the condition to reflect the appropriate requirements for engines located at a major source of hazardous air pollutants (HAPs).
7	2.1. A.5.	Updated State Best Available Control Technology emission standards for all engines to be equal to the NSPS, Subpart JJJJ standards for NOx and CO, and good combustion practices and burning of landfill gas for all other pollutants.
8-17	3	Updated the General Conditions to the most recent version (Version 5.2. 04/03/2018).

5. Changes in Equipment

LFG-fired engine/generator (ID No. ES-EG3) removed at facility's request. The engine was damaged and is no longer on site.

Title V Equipment Editor (TVEE) was updated on August 10, 2018.

The facility's permitted emission sources are as follows:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-EG1 **MACT ZZZZ, NSPS JJJJ**	One landfill gas-fired, lean burn, spark ignition engine/generator unit (1468 hp engine, 1059 kW generator, Jenbacher Model No. 320 GS-L.L, C81)	None	None
ES-EG2 **MACT ZZZZ, NSPS JJJJ**	One landfill gas-fired, lean burn, spark ignition engine/generator unit (1468 hp engine, 1059 kW generator, Jenbacher Model No. 320 GS-L.L, C81)	None	None

6. NSPS, NESHAP, PSD, 112(r), CAM & Attainment Status

- **NSPS** –
  - ✓ The LFG-fired engine/generator units (ID Nos. ES-EG1 and ES-EG2) are subject to 40 CFR 60, Subpart JJJJ "Stationary Spark Ignition Internal Combustion Engines," since the engines were manufactured in September 2009.
- **NESHAP** –
  - ✓ The LFG-fired engine/generator units (ID Nos. ES-EG1 and ES-EG2) are subject to 40 CFR 63, Subpart ZZZZ "Reciprocating Internal Combustion Engines" and are considered as "new" emergency engines located at a Major Source of HAPs under this regulation.
- **PSD –** The facility is not a major source for PSD purposes. PSD is not impacted by this permit application.
  - ✓ Durham County has not triggered increment tracking under PSD.
- **112(r) –** The facility does not store any of the listed 112(r) chemicals in amounts that exceed the threshold quantities. Therefore, the facility is not required to maintain a written Risk Management Plan (RMP).
- **CAM –** CAM does not apply to this facility.
- **Attainment status** – Durham County is in attainment for all criteria pollutants.

7. Regulatory Review

This facility is subject to the following air quality regulations, in addition to the requirements in the General Conditions:

- 15A NCAC 02D .0516, Sulfur Dioxide Emissions from Combustion Sources
- 15A NCAC 02D .0521, Control of Visible Emissions
- 15A NCAC 02D .0524, New Source Performance Standards, 40 CFR 60, Subpart JJJJ
- 15A NCAC 02D .1111, Maximum Achievable Control Technology, 40 CFR 63, Subpart ZZZZ
- NCGS §62-133.8 (g), SB3 BACT Analysis

15A NCAC 02D .0516, "Sulfur Dioxide Emissions from Combustion Sources"
Sulfur dioxide emissions from each LFG-fired engine are limited to 2.3 pounds per million Btu heat input. Treated LFG is considered equivalent to natural gas and its combustion produces negligible emissions of sulfur dioxide. No monitoring, recordkeeping or reporting is required for LFG combustion. Continued compliance is expected.

15A NCAC 02D .0521, "Control of Visible Emissions"
This permit condition was previously a part of the facility's permit, however it appears to have been erroneously omitted in recent revisions, even though it was still cited; the permit condition has been restored. All permitted sources at the facility are limited to a six-minute average opacity of 20%. No visible emissions have been observed from the engines during the site inspections or stack testing, and neither the facility nor DAQ have received complaints from nearby residents. No monitoring, recordkeeping or reporting is required for LFG combustion. Continued compliance is expected.

15A NCAC 02D .0524, New Source Performance Standards, 40 CFR 60, Subpart JJJJ
The engines were manufactured in September 2009 and are subject to New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines – specifically the standards that apply to LFG-fired lean burn engines with a maximum engine power greater than or equal to 500 HP and manufactured after July 1, 2007, but before July 1, 2010. LFG-fired engines have no fuel requirements but must be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions. The engines must also meet the emission standards in §60.4233(e). The applicable NSPS emissions standards are as follows:

Pollutant	Emission Standard*		
NOx	3.0 g/hp-hr	-or-	220 ppmvd at 15% O_2
CO	5.0 g/hp-hr	-or-	610 ppmvd at 15% O_2
VOC	1.0 g/hp-hr	-or-	80 ppmvd at 15% O_2

* The permittee may choose to comply with the emission standard in either g/hp-hr or ppmvd at 15% O_2.

None of the facility's engines have been certified to these standards for combusting LFG, and must demonstrate compliance via periodic source testing.

LFG contains small amounts of nitrogen, oxygen, carbon monoxide (CO), and nonmethane organic compounds including volatile organic compounds (VOC). Some of the nitrogen content in the fuel is oxidized to nitrogen oxides (NOx) and emitted along with other LFG constituents during the combustion process. Additional NOx is formed from the high temperature oxidation of nitrogen present in the combustion air. Most CO emissions result from incomplete combustion of LFG. Good combustion practices employed by MP Durham, LLC provide compliance with the emissions standards.

MP Durham has conducted representative testing of one engine on an annual basis to show compliance for all three engines. The testing condition in this section has been revised to reflect that the facility shall test the engines on a rotating basis such that each engine is tested at least once every three years. Source testing performed at the facility has consistently demonstrated compliance with the standards as shown in the table below:

Test Date	Engine	Load During Test (kW)	CO		NOx		VOC
			ppmvd	g/hp-hr	ppmvd	g/hp-hr	ppmvd
06/21/12	1	1059	359.9	-----	45.1	-----	0
	3	1059	353.1	-----	48.2	-----	0
06/14/13	2	1051	363	2.85	42	0.542	30.3
06/23/14	1	1000	262	2.25	45	0.636	31.3
06/16/15	3	1059	283	2.40	40.3	0.556	0.76
08/09/16	2	1051	278.8	2.39	37.7	0.531	8.67
08/17/17	1	1025	287.2	2.54	37.2	0.54	7.99
NSPS Emission Standard			610	5.0	220	3.0	80
Compliance Indicated?			Yes	Yes	Yes	Yes	Yes

All source test results have reviewed and accepted by the NCDAQ Stationary Source Compliance Branch. Continued compliance is expected.

15A NCAC 02D .1111, Maximum Achievable Control Technology, 40 CFR 63, Subpart ZZZZ

The engines were manufactured in September 2009 and are subject to NESHAP requirements for stationary Spark Ignition Reciprocating Internal Combustion Engines (SI RICE). Each was constructed after December 2002, is more than 500 horsepower (HP) and burns exclusively landfill gas as fuel.

The existing NESHAP condition in the permit for the engines is based on the facility being an area source of hazardous air pollutants (HAP) with a potential to emit of no more than 10 tons of any individual HAP and no more than 25 tons of total HAP in any 12-month period. However, DAQ recently became aware of performance test results that indicate significant levels of formaldehyde emissions for spark-ignition RICE combusting LFG. Formaldehyde is a Title III HAP, and is not present in such large quantities in LFG, but is formed during the combustion process. MP Durham, LLC not only has the potential to emit in excess of 10 tons of formaldehyde in a 12-month period, its annual emissions of this HAP, as reported in the CY2016 AQEI, have exceeded 10 tons.

Therefore, the engines are subject to the 40 CFR 63 Subpart ZZZZ standards that apply to new LFG-fired SI RICE with a site rating of more than 500 brake HP located at a major source of HAP rather than the standards for an area source. These engines are required to meet the initial notification requirements of 40 CFR 63.6645(f) and must comply with the monitoring, recordkeeping and reporting requirements in 40 CFR 63.6625(c), 63.6650(g), and 63.6655(c). However, LFG-fired engines at major sources do not have to meet emissions or operational limits. Their applicable requirements include operating in a manner which reasonably minimizes HAP emissions, monitoring and recording of daily fuel usage, maintaining daily fuel usage monitor records, and annual reporting. The permit condition has been revised to reflect the applicable requirements for a major source of HAPs. Compliance is expected.

State BACT Analysis [NC GS §62-133.8 (g)] – STATE ENFORCEABLE ONLY

North Carolina General Statute §62-133.8 (g) requires MP Durham LLC to control the emissions of carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compounds (VOCs), particulate matter (PM_{10}/$PM_{2.5}$), sulfur dioxide (SO_2), mercury and lead from the three engines to the maximum extent that has been determined to be achievable at the facility using Best Available Control Technology (BACT). Since the initial BACT analysis was completed for this facility, DAQ has adopted a policy to set State BACT for Biogas and LFG-fired engines to be equivalent to the emission standards of NSPS Subpart JJJJ, and the applicant has requested that this change be reflected in the permit. The following analysis was performed for this purpose:

Best Available Control Technology (BACT) means an emissions limitation based on the maximum degree of reduction in the emission of air pollutants that is achievable for a facility, taking into account energy, environmental, and economic impacts and other costs. A biomass combustion process at any new renewable energy facility that delivers electric power to an electric utility shall meet BACT. In the case of co-firing biomass with non-biomass fuels, Senate Bill 3 (SB3) will apply only to that portion of potential emissions that result from biomass combustion. There is no significance level or lesser quantity cutoff at which SB3 would not be triggered.

A. BACT for NOx:

NITROGEN DIOXIDE (NOx) BACT Analysis

During combustion, NOx is formed from two main sources. NOx emissions formed through the oxidation of the fuel bound nitrogen are called fuel NOx. NOx emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NOx and are a function of combustion temperature. Landfill gas does not contain significant amounts of fuel bound nitrogen. Therefore, NOx emissions from an engine/generator unit will mainly originate as thermal NOx.

Nitrogen oxide control methods may be divided into three categories: pre-combustion type control, NOx formed during combustion control and post-combustion emissions reduction. Pre-combustion type controls pre-treat landfill gas prior to the engine to remove pollutants that are harmful to engine components. Control methods used to reduce the formation of NOx in the combustion process are mostly inherent to the engine. Post-combustion technologies reduce the NOx emissions in the flue gas stream after the NOx has been formed in the combustion process. All of these methods may be used to achieve the various degrees of NOx reductions.

Section 1.0 - Identification of NOx Control Options

The different types of types of emission controls reviewed by this BACT analysis are as noted below:

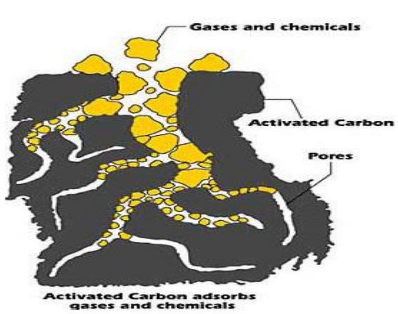
Pre-combustion type control:
- Siloxane removal system using refrigeration/chillers
- Siloxane removal system using carbon adsorption

In-combustion type controls (may vary between different models and manufacturers):
- Good combustion practices
- Turbocharger, intercooler
- Lean burn technology
- Electronic air-to-fuel ratio controller

Post-combustion type controls:
- Selective catalytic reduction (SCR)
- Non-selective catalytic reduction (NSCR)
- Selective non-catalytic reduction (SNCR)

1.1 Siloxane removal system:
- Using refrigeration/chillers:
  This technology is used to chill the inlet air and landfill gas to remove moisture, siloxanes and various other pollutants found in landfill gas prior to combustion in the engine. The results of this control technology are considered to result largely from a scrubbing effect with gaseous siloxane compounds being dissolved into the condensate being formed, rather than condensation of the siloxane compounds themselves. The chilling of inlet air and gas fuel before combustion would involve purchasing and installing a compressor, chiller/refrigerant unit, reheat unit for the landfill gas, and other ancillary equipment. [Reference Calabasas Landfill Micro Turbine Facility and Rapid City Landfill Gas Study]

- Using carbon adsorption:
  This type of siloxane removal system is a pretreatment system that removes harmful siloxane from landfill gas by passing warm air through the treatment bed (desiccant), and then the out-flow gas is combusted in a thermal oxidizer. A desiccant (example: activated carbon) is a substance that has the ability to attract and hold gas molecules (adsorption) from the surrounding substance. Activated carbon (adsorbent) is used to attract to its surface molecules of gas (adsorbate) with which it is in contact. Physical adsorption depends on Van Der Waals forces of attraction between molecules and resembles condensation of liquids. The following picture illustrates adsorption or surface attraction of gases and chemicals onto activated carbon:



Each control technology is considered and those that are infeasible based on physical, chemical, prohibitive cost, engineering principles and/or are undemonstrated in the gas-to-energy type industries are eliminated.

a. Siloxane removal system cost estimate:
The Biogas Cleanup System Cost Estimator Toolkit Training and User Instruction Manual, Version 1, prepared by the Gas Technology Institute was used to estimate the cost of a siloxane removal system. The tool kit methodology provides generic cost categories and default assumptions to estimate the installed costs of a siloxane removal system. Direct costs are required for certain key elements, such as the capital and O&M costs. Other costs, such as system installation, are then estimated from a series of input percentages or factors applied to the purchased equipment costs. The default percentages used in the spreadsheet were taken from those used by industry as presented in the EPA Air Pollution Control Cost Manual. This methodology provides a rough order-of-magnitude-level cost estimates. The only input required for making this level of estimate is the biogas volumetric flow rate or the equivalent engine power.

In order to facilitate estimation of the vendor cost data for use in the tool kit, a best-fit regression analysis was performed of the capital and O&M vendor cost data versus flow rate to obtain correlation equations for use in the tool kit. These equations are then applied to the user input landfill gas flow data in the spreadsheet using the calculation scheme. The siloxane removal system equipment cost (SRSEC) for a siloxane removal system is calculated in the spreadsheet as follows:

Sample calculation for a Caterpillar Model 3520C, 2233 hp engine with a landfill gas inlet volumetric flow rate of 520 scfm:

SRSEC ($) = 35,064 x (total flow rate, scfm) $^{0.375}$
SRSEC ($) = 35,064 x (520 scfm) $^{0.375}$ $\rightarrow$ $365,900.00
The siloxane removal system Operation & Maintenance costs are calculated in the spreadsheet by:
O&M ($) = 2047 x (total flow rate, scfm) $^{0.399}$
O&M ($) = 2047 x (520 scfm) $^{0.399}$ $\rightarrow$ $24,820.00

In addition to estimating the capital (purchased equipment) and O&M costs for the siloxane removal system, the following cost categories are used to describe the annual cost:

i. Total Equipment Costs (TEC), which include the capital costs of the siloxane removal system and auxiliary equipment, instrumentation, sales tax, and freight;
ii. Direct Installation Costs (DIC), which are the construction-related costs associated with installing the control device;
iii. Indirect Capital Costs (ICC), which include installation expenses related to engineering and start-up;
iv. Direct Operating Costs (DOC), which include annual increases in operating and maintenance costs due to the addition of the control device; and
v. Indirect Operating Costs (IOC), which are the annualized cost of the control device system and the costs due to tax, overhead, insurance, administrative burdens and capital recovery.

From these costs the Total Annual Cost (TAC) is calculated, which is the sum of the Direct Operating and Indirect Operating Costs. Table 1 is an example calculation of a 2233 horsepower engine with an inlet landfill gas flow rate of 520 scfm. Table 2 compares the costs of several other size units in order to compare costs.

Table 1: Total Annual Cost Evaluation

Input Value and Units		
Parameter:	Value:	Units:
Landfill gas heating value	500	Btu/ft^3
Engine efficiency	32	%
Inlet flow rate	520	scfm
Engine power	2233	hp
Generator power	1600	kW
Cost items	Cost Factor	Value
DIRECT CAPITAL COSTS (DCC)		
(1) Siloxane removal system equipment costs (SRSEC)	-------------------	$365,900
(2) Auxiliary equipment	5% of equipment costs (SRSEC)	$18,295
(3) Freight	5% of SRSEC	$18,295
(4) Sales Tax	10% of (SRSEC + auxili +freight)	$36,590
Subtotal: Total Equipment Cost (TEC)	(1) + (2) +(3) + (4)	$439,080
(5) Direct Installation Costs		
(a)Foundation and structural support	8% of TEC	$35,126
(b) Handling & erection	14% of TEC	$61,471
(c)Electrical	4% of TEC	$17,563
(d) Piping	2% of TEC	$8,782
(e)Insulation	1% of TEC	$4,391
(f) Painting	1% of TEC	$4,391
Subtotal: Total Direct Installation Costs (DIC)	(a) + (b) + (c) + (d) + (e) + (f)	$131,724
Total DCC	TEC + DIC	$570,804

INDIRECT CAPITAL COSTS (ICC)		
(1) Indirect installation costs (IIC)		
(a) General facilities	5% of TEC	$21,954
(b) Engineering and home office fees	10% of TEC	$43,908
(c) process contingency	10% of TEC	$43,908
(2) Other indirect costs (OIC)		
(a) Siloxane monitor	Engineering estimate	$75,000
(b) Startup and performance testing	1% of TEC	$4,391
(c) Spare parts	1% of TEC	$4,391
(d) Contractor fees	10% of TEC	$43,908
Total ICC:	IIC + OIC	$237,460
PROJECT CONTINGENCY	15% of (DCC + ICC)	$121,240
RETROFIT COSTS	0% of TIC	$0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + Project Contingency	$929,504
DIRECT OPERATING COSTS (DOC)		
(1) Operating labor		
(a)Operator	0.5 hrs/shift x 3 shifts/day x 365 days/year x $40/hour = 21,900	$21,900
hr/shift	0.5	-----------
Pay rate	$40	-----------
Operating hours	3 shifts per day	-----------
(b) Supervisor	15% of operator cost (0.15 x 21,900)	$3,285
(2) Maintenance (labor and material)	1.5% of TCI	$13,943
(3) Siloxane removal system media replacement + energy replacement	-----------	$24,820
(4) Siloxane system periodic testing	Engineering estimate	$24,000
Total DOC:	(1) + (2) + (3) + (4)	$87,948
INDIRECT OPERATING COSTS (IOC):		
(1) Overhead	60% of {(operator labor + maintenance) = 1(a) + 1(b) + 2}	$23,477
(2) Property taxes	1% of total capital investment	$9,295
(3) Insurance	1% of total capital investment	$9,295
(4) Administration	2% of total capital investment	$18,590
(5) Capital recovery costs (CRC)	CRF x TCI	$132,362
Capital recovery factor (CRF)	0.1424	-----------
Interest rate	7%	-----------
Annualization years	10	-----------
Total IOC:	(1) + (2) + (3) + (4) + (5)	$193,020
TOTAL ANNUAL COST (TAC)	**DOC + IOC**	**$280,968**

<u>Allowable exhaust emission standards for NSPS, Subpart JJJJ, spark ignition engines:</u>
Engine size = 2233 hp
NOx: 2.0 g/hp-hr
CO: 5.0 g/hp-hr
[Per 40 CFR §60.4233(e) and Table 1]

Emissions were calculated using the NSPS, Subpart JJJJ allowable emission limits:

$$\frac{5.0\ g\ CO}{hp-hr}\ x\frac{1\ lbs\ CO}{453.59\ g}\ x\frac{2233\ hp}{engine}x\frac{8760\ hours}{year}x\frac{1\ ton}{2000\ lbs}=\frac{107.81\ tons\ CO}{year}$$

$$\frac{2.0\ g\ NOx}{hp-hr}\ x\frac{1\ lbs\ NOx}{453.59\ g}\ x\frac{2233\ hp}{engine}x\frac{8760\ hours}{year}x\frac{1\ ton}{2000\ lbs}=\frac{43.13\ tons\ NOx}{year}$$

The CO and the NOx emission rates using the siloxane removal system as a control device helps prevent silica buildup/coating on engine parts and lessens the formation of CO and NOx due to the more efficient combustion landfill gas in the engine (approximately 24% control efficiency).

$$\frac{5.0\ g\ CO}{hp-hr}\ x\frac{1\ lbs\ CO}{453.59\ g}\ x\frac{2233\ hp}{engine}x\frac{8760\ hours}{year}x\frac{1\ ton}{2000\ lbs}\ x\ (1-\ 0.24)\ control\ eff.$$
$$=\ \frac{81.94\ tons\ CO}{year}$$

$$\frac{2.0\ g\ NOx}{hp-hr}\ x\frac{1\ lbs\ NOx}{453.59\ g}\ x\frac{2233\ hp}{engine}x\frac{8760\ hours}{year}x\frac{1\ ton}{2000\ lbs}\ x\ (1-\ 0.24)\ control\ eff.$$
$$=\ \frac{32.78\ tons\ NOx}{year}$$

(107.81 – 81.94 = 25.87 tpy CO removed using the siloxane removal system)
(43.13 – 32.78 = 10.35 tpy NOx removed using the siloxane removal system)

The annualized cost of the Siloxane Removal System (CO) = $280,968 ÷ 25.87 tons = $10,861/ton of CO removed.

The annualized cost of the Siloxane Removal System (NOx) = $280,968 ÷ 10.35 tons = $27,146/ton of NOx removed.

The Biogas Cleanup System Cost Estimator Toolkit kit methodology was used to provide cost estimates for Siloxane Removal systems for landfill gas-fired spark ignition engines/generator units of varying horse power ratings and inlet flow rates. The addition of this control technology indicates that it is cost prohibitive regardless of the engine size and inlet flowrate.

Table 2: Siloxane System Refrigeration-type Pre-combustion Control

Engine Size	Inlet Flow Rate	Generator Size	Cost of System	NOx Removed by Control	CO Removed by Control	$$/ton NOx Removed	$$/ton CO Removed
2233 hp	520 scfm	1600 kW	$280,968	10.35 tpy	25.87 tpy	$27,173/ton	$10,861/ton
1448 hp	327 scfm	1059 kW	$259,201	6.71 tpy	16.78 tpy	$37,288/ton	$14,910/ton
114 hp	26 scfm	85 kW	$146,676	< 1.0 tpy	1.32 tpy	$146,676/ton	$111,119/ton

Due to the economic impact involved with the purchase of a pre-combustion siloxane removal system for an engine/generator unit, and the environmental benefit to the atmosphere, this control technology option was not considered further.

1.2 Good combustion practices:
This is a general term for the operation of engines according to the manufacturer's recommendations, and good maintenance procedures.

1.3 Exhaust gas turbocharger, intercooler:
A turbocharger is device that increases an internal combustion engine's efficiency and power output by forcing extra air into the combustion chamber. This improvement over a naturally aspirated engine's output results because the turbine can force more air, and proportionately more fuel, into the combustion chamber than atmospheric pressure alone. Compression of the air prior to introduction into the cylinder results in compression heating. This may be detrimental from the point of view of NOx formation because it increases the peak combustion temperature. An intercooler may be installed between the compressor and the intake valve to reduce this heating.

1.4 Lean burn technology:
Lean burn technology refers to the use of lean fuel to air mixtures in an internal combustion engine. The stoichiometric air-to-fuel ratio is on the order of 15:1 (15 parts air to 1 part fuel). True lean-burn air-to-fuel ratio is much higher than stoichiometric. The central idea of this technology is to provide an environment that will efficiently combust the available fuel at low temperatures. Lean-burn engines enjoy higher fuel economy and cleaner emissions than conventionally tuned engines. By nature, they use less fuel and emit fewer unburned hydrocarbons and greenhouse gases while producing equivalent power of a like-sized "normal" combustion engine. They achieve lean-burn status by employing higher combustion chamber compression ratios (higher cylinder pressure), significant air intake swirl and precise lean-metered direct fuel injection.

1.5 Electronic air-to-fuel ratio controller:
An air-to-fuel ratio controller monitors engine performance parameters and automatically adjusts the air-to-fuel ratio and ignition timing to maintain efficient fuel combustion, which also minimizes air pollutant emissions. A lean burn engine unfortunately burns very hot and can damage engine components if the engine is placed under high load at the stoichiometric fuel–air mixture. Due to the high temperatures at this mixture, detonation of the fuel–air mix shortly after maximum cylinder pressure is possible under high load (referred to as knocking or pinging).

1.6 Selective catalytic reduction (SCR):
The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The reactions take place on the surface of the catalyst. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades, ammonia slip will increase.

1.7 Non-selective catalytic reduction (NSCR):
NSCR (also called a 3-way catalyst) is a post combustion add on control for controlling rich-burn type engines. Exhaust from the engine is passed through a metallic or ceramic honeycomb covered with precious metal catalyst.

1.8 Selective Non-Catalytic Reduction (SNCR):
Non-catalytic processes such as selective non-catalytic reduction (SNCR) use NH_3 or urea injection into high temperature (generally about 1800 °F) combustion zones or flue gas. SNCR is a post-combustion NOx control technology that reduces NOx to nitrogen gas and water vapor by reacting the flue gas with a chemical reagent. SNCR is "selective" in that the reagent reacts primarily with NOx. The chemical reaction for this technology is driven by higher temperatures (typically form 1600 °F to 2100 °F) than normally found in IC engine exhaust sources. The optimal temperature range for SNCR is very important because outside of it, either more NH_3 slips through the system or more NOx is generated than is being chemically reduced. NH_3 slip has the potential to affect combustor operation as well through ammonium bisulfate formation and subsequent corrosion on the downstream components. SNCR systems can achieve from 50 to 95 percent NOx removal (depending on the fuel), and are primarily applicable to boilers that can maintain a relatively constant temperature for the reaction.

Section 2.0 - Elimination of Technically and Economically Infeasible NOx Control Options
Each control technology was considered and those that were infeasible based on physical, chemical, prohibitive cost, and engineering principles or commercially unavailable were eliminated.

2.1 Siloxane removal system (chiller type and carbon adsorption type):
Due to the economic impact involved with the purchase of a pre-combustion siloxane removal system for a landfill gas-fired engine/generator unit and the environmental benefit to the ambient air, this control technology option is cost prohibitive (See Table 1 of this review) and was not considered further.

2.2 Good combustion practices, exhaust gas turbocharger, electronic air-to-fuel ration controller and intercooler:
These are considered to be technically feasible in-combustion type control technologies and will be considered further.

2.3 Selective catalytic reduction (SCR) & non-selective catalytic reduction (NSCR)
Landfill gas contains contaminants such as siloxanes, sulfur compounds, and halides that are detrimental to a catalyst. The contaminants will clog up the catalyst, making that catalyst ineffective in a short period of time. Papers written by the Combustion Group of the US EPA (12/99), a US EPA White paper written in September 1998 for the MACT for Digester and Landfill gases, and in a US EPA memorandum (2007) for spark ignition engines, the EPA agrees the siloxanes contaminate catalysts placed in the exhaust streams of landfill gas-fired engines. This control technology was not considered any further.

2.4 Selective Non-catalytic reduction (SNCR):

The successful operation of this technology is very dependent on flue gas temperature (typically 1600 to 2100 °F). The exhaust flue gas temperature of most engines will be approximately 900 °F or less. In order to install the SNCR control technology on the engine exhaust, the flue gas would have to be heated up to operation temperature which would increase NOx and CO (if heated using fuel) emissions and increase the operation cost of the technology. This technology is generally used on boilers where the chemical is injected directly into the firebox. There have not been any proven applications of this technology on landfill gas-fired spark ignition engines. This control technology is not considered any further.

Section 3.0 - Ranking of Technically Feasible NOx Control Options

The feasible control technologies are evaluated on the basis of economic, environmental, and energy considerations.

RACT/BACT/LAER Clearing House Summary for NOx emissions from landfill gas-fired engines located in Attainment Areas. A review of the EPA RBLC from other states in the US and recent BACT analyses of landfill gas-to-energy projects in North Carolina indicates that the NOx emission limits for landfill gas-fired engines were established using good combustion practices, inherent controls, using lean burn engines.

BACT determinations in North Carolina:

The State of North Carolina has issued several State BACT determinations for NOx and CO for landfill gas-fired, lean burn spark ignition engines in recent years. Regulatory source testing has been performed at most of the permitted gas-to-energy facilities. This information was used mainly in this engineering review because it reflects the gas quality in the state of North Carolina. The following table reflects actual test results that have been submitted and reviewed by the DAQ Compliance branch.

Table 3: Test results using test methods in NSPS Subpart JJJJ

Name of Facility	Facility ID No.	Test Results (NOx)	Test Results (CO)	Approval Date
Buncombe County	1100542	248.5 ppm	42.9 ppm	June 26, 2017
CII Methane	5100209	0.45 g/hp-hr	3.02 g/hp-hr	January 17, 2018
Columbus County (2 engines)	2400160	1.88 g/hp-hr	0.76 g/hp-hr	May 30, 2013
		1.63 g/hp-hr	0.68 g/hp-hr	
Davidson Gas Producers, LLC	2900359	0.61 g/hp-hr	2.8 g/hp-hr	February 26, 2018
Gaston County (3 engines)	3600339	0.98 g/hp-hr	2.7 g/hp-hr	June 13, 2018
		0.77 g/hp-hr	2.7 g/hp-hr	
		0.84 g/hp-hr	2.4 g/hp-hr	
Greenville Gas Producers, LLC	4500317	No data (not operated)	No data (not operated)	No data (not operated)
Iredell Transmission, LLC	4900262	0.4 g/hp-hr	2.9 g/hp-hr	February 16, 2018
MP Durham	3200375	0.54 g/hp-hr	2.54 g/hp-hr	May 22, 2018
MP Wayne	9600269	0.587 g/hp-hr	2.73 g/hp-hr	May 22, 2018
Onslow Power Producers, LLC	6700162	0.56 g/hp-hr	3.01 g/hp-hr	June 21, 2016
Robeson County LFG-to-Energy Project	7800222	0.85 g/hp-hr	2.42 g/hp-hr	May 21, 2018
Rockingham County Landfill	7900174	1.0 g/hp-hr	2.2 g/hp-hr	May 13, 2016
Surry County Landfill	8600170	0.34 g/hp-hr	3.49 g/hp-hr	October 13, 2017
UNC-Chap. Hill LFG-to-Energy	6800095	0.45 g/hp-hr	3.01 g/hp-hr	April 13, 2018
Uwharrie Mountain Renewable Energy (2 engines)	6200087	0.36 g/hp-hr	2.4 g/hp-hr	February 20, 2018
		0.39 g/hp-hr	2.6 g/hp-hr	
White Street Renewables	4101249	No data (not operated)	No data (not operated)	No data (not operated)

Siloxanes are substances, commonly found in household products like shampoo, cosmetics and detergents which break down during combustion and lead to hard silica and silicate deposits in combustion chambers, exhaust manifolds and exhaust stacks. These deposits on the cylinders and valve faces lead to a grinding action and increased valve seat wear. In many cases where siloxanes are present in the fuel, siloxane buildup on cylinder heads and on pistons physically reduces cylinder volume and increases the compression ratio, driving up cylinder pressures and pollutant emissions. Although most of the engine used at gas-to-energy facilities have been adapted to burn landfill gas, vendors do not certify the engines.

Section 4.0 Evaluation of Technically and Economically Feasible NOx Control Options

Compliance with the NOx BACT limits will be determined utilizing the annual performance test in accordance with 40 CFR Subpart JJJJ. The lean burn technology and other inherent controls on the engine will help to minimize NOx emissions.

Economic Impact – The engine is manufactured with a lean burn design because of the advantages that it offers for burning landfill gas. The inherent controls on the engine are part of the engine design and cost. No adverse economic impact is expected.

Environmental Impact – This engine/generator unit will be utilizing landfill gas as a fuel which will be combusted and used to produce electricity. Burning landfill gas helps to reduce odors at the landfill, destroys air pollutants associated with landfill gas emissions, and helps prevent methane (a greenhouse gas) from migrating into the atmosphere which contributes to smog and climate change.

Energy Impact – Although not detailed, there is typically no adverse energy impacts when burning the landfill gas that is generated from the decomposition of municipal solid waste.

Section 5.0 - Selection of BACT for NOx

All of the Counties in North Carolina are currently in attainment for nitrogen dioxide. There are no practically or legally cognizable environmental impacts from the small amount of NOx emissions from gas-to-energy facilities that burn landfill gas. Using EPA's economic principles, the favorable effects of a regulation like BACT are the benefits, and the foregone opportunities or losses in utility are the costs. Subtracting the total costs from the total monetized benefits provides an estimate of the regulation's net benefits to society. An efficient regulation is one that yields the maximum net benefit, assuming that the benefits can be measured in monetary terms. According to the EPA, the most economically efficient policy is the one that allows for society to derive the largest possible social benefit at the lowest social cost. This occurs when the *net* benefits to society (i.e., total benefits minus total costs) are maximized.

Based on the environmental impact, the marginal environmental gains of add on controls (≈ 24% efficiency), the prohibitive economic cost for add on controls and facility test data from other gas-to-energy facilities in North Carolina, the NOx BACT limit for the landfill gas-fired engine/generator unit is:

- Good combustion practices and the New Source Performance Subpart JJJJ limit. Compliance with this limit can be in either ppmvd at 15% O_2 or g/hp-hour.

This limit more accurately reflects the quality of the landfill gas at facilities across North Carolina, the test results from facilities in this State and the degradation of engines due to landfill gas contaminants over the life of the engine in between major overhauls. This limit is also the allowable emission rate for all other engines permitted in the State of North Carolina that are not classified as gas-to-energy units.

B. BACT for CO:

CARBON MONOXIDE (CO) BACT Analysis

CO is a colorless, odorless, tasteless gas that has adverse health effects. CO is created from the incomplete combustion of landfill gas in internal combustion engines. Landfill gas contains contaminants such as siloxanes, sulfur compounds, and halides. These contaminants can build up and form deposits on engine parts during combustion and can adversely affect engine performance over time. Decreased engine performance results in increased CO emissions over the life of the engine. Given the appropriate time and temperature, CO will react to produce CO_2 during the combustion process. Employing good combustion practices to ensure complete combustion normally controls CO emissions.

Carbon monoxide control methods may be divided into three categories: pre-combustion type control, CO formed during combustion control and post-combustion emissions reduction. Pre-combustion type controls pre-treat landfill gas prior to the engine to remove pollutants that are harmful to engine components and help with combustion efficiency. Control methods used to reduce the formation of CO in the combustion process are mostly inherent to the engine. Post-combustion technologies reduce the CO emissions in the flue gas stream after the CO has been formed in the combustion process. All of these methods may be used to achieve the various degrees of CO reductions.

Section 1.0 - Identification of CO Control Options

The different types of types of emission controls for internal combustion engines reviewed by this BACT analysis are as noted below:

Pre-combustion type:
- Siloxane removal system using refrigeration/chillers
- Siloxane removal system using carbon adsorption

In-combustor type:
- Good combustion practices
- Lean burn technology
- Exhaust gas turbocharger, intercooler

Post-combustion type:
- Oxidation catalyst
- Non-selective catalytic reduction (NSCR)
- Electronic air-to-fuel ratio controller

1.1 Siloxane removal systems using refrigeration/chillers or carbon adsorption:

This is the same system as described in Section A for the NOx evaluation.

1.2 Good Combustion Practices:

Good combustion practices for a landfill gas fired engine/generator unit is the operation, monitoring, maintenance and overhauling of the engine based on the recommendations of the manufacturer of the engine which will assure optimal combustion conditions for minimizing air emissions.

1.3 Exhaust gas turbocharger, intercooler:

A turbocharger is device that increases an internal combustion engine's efficiency and power output by forcing extra air into the combustion chamber. This improvement over a naturally aspirated engine's output results because the turbine can force more air, and proportionately more fuel, into the combustion chamber than atmospheric pressure alone. Compression of the air prior to introduction into the cylinder results in compression heating. An intercooler may be installed between the compressor and the intake valve to reduce this heating.

1.4 Lean Burn Technology:

Lean burn technology refers to the use of lean fuel to air mixtures in an internal combustion engine. The stoichiometric air-to-fuel ratio is on the order of 15:1 (15 parts air to 1 part fuel). True lean-burn air fuel ratio is much higher than stoichiometric. The central idea of this technology is to provide an environment that will efficiently combust the available fuel at low temperatures. Lean-burn engines enjoy higher fuel economy and cleaner emissions than conventionally tuned engines. By nature, they use less fuel and emit fewer unburned hydrocarbons and greenhouse gases while producing the equivalent power of a like-sized "normal" combustion engine. They achieve lean-burn status by employing higher combustion chamber compression ratios (higher cylinder pressure), significant air intake swirl and precise lean-metered direct fuel injection.

1.5 Electronic air-to-fuel ratio controller:

An air-to-fuel ratio controller monitors engine performance parameters and automatically adjusts the air-to-fuel ratio and ignition timing to maintain efficient fuel combustion, which also minimizes air pollutant emissions. A lean burn engine unfortunately burns very hot and can damage engine components if the engine is placed under high load at the stoichiometric fuel–air mixture. Due to the high temperatures at this mixture, detonation of the fuel–air mix shortly after maximum cylinder pressure is possible under high load (referred to as knocking or pinging).

1.6 Non-selective Catalytic Reduction (NSCR):

In the catalyst industry, Non-Selective Catalytic Reduction (NSCR) is a common reference to Three-Way Catalysts. NSCR catalysts address carbon monoxide (CO) and hydrocarbon (HC) exhaust emissions via oxidation, while also converting nitrogen oxides (NOx) via reduction.

Section 2.0 - Elimination of Technically and Economically Infeasible CO Control Options

Each control technology was considered and those that were infeasible based on physical, chemical, prohibitive cost, and engineering principles or commercially unavailable were eliminated.

2.1. Siloxane Removal System:

Due to the economic impact involved with the purchase of a pre-combustion siloxane removal system for a landfill gas-fired engine/generator unit and the environmental benefit to the ambient air, this control technology option is cost prohibitive (See Table 1 of this review) and was not considered further.

2.2 Catalytic oxidation and non-selective catalytic reduction (NSCR):

The preface for the RICE MACT and the spark ignition NSPS state that landfill gas contains a family of silicon-based gases collectively called siloxanes. Combustion of siloxanes form compounds that have been known to foul fuel systems, combustion chambers, and post-combustion catalyst, rendering them inoperable in a short period of time. As documented by the US EPA, oxidation catalysts and non-selective catalytic reduction (NSCR) have been determined to be a technically infeasible control options for landfill gas-fired engines. These control technology options were not considered further.

2.3 Good combustion practices, lean burn technology, exhaust gas turbocharger and intercooler:

These are considered to be technically feasible in-combustion type control technologies and will be considered further.

Section 3.0 Ranking of Technically and Economically Feasible CO Control Options

A review of the EPA RBLC and recent BACT analyses of gas-to-energy projects in North Carolina indicates that the CO emission limits for landfill gas-fired engines were established using good combustion practices, inherent controls, and lean burn engines.

Section 4.0 Evaluation of Technically and Economically Feasible CO Control Options

Compliance with the CO BACT limit will be determined utilizing the annual performance test in accordance with 40 CFR Subpart JJJJ. The lean burn technology and other inherent controls on the engine will help to minimize CO emissions.

Economic Impact – The engine is manufactured with a lean burn design because of the advantages that it offers for burning landfill gas. The inherent controls on the engine are part of the engine design and cost. No adverse economic impact is expected.

Environmental Impact – This engine/generator unit will be utilizing landfill gas as a fuel which will be combusted and used to produce electricity. Burning landfill gas helps to reduce odors at the landfill, destroys air pollutants associated with landfill gas emissions, and helps prevent methane (a greenhouse gas) from migrating into the atmosphere which contributes to smog and climate change.

Energy Impact – Although not detailed, there is typically no adverse energy impacts when burning the landfill gas that is generated from the decomposition of municipal solid waste.

Section 5 - Selection of BACT for CO

All of the Counties in North Carolina are currently in attainment for nitrogen dioxide. There are no practically or legally cognizable environmental impacts from the small amount of NOx emissions from gas-to-energy facilities that burn landfill gas. Using EPA's economic principles, the favorable effects of a regulation like BACT are the benefits, and the foregone opportunities or losses in utility are the costs. Subtracting the total costs from the total monetized benefits provides an estimate of the regulation's net benefits to society. An efficient regulation is one that yields the maximum net benefit, assuming that the benefits can be measured in monetary terms. According to the EPA, the most economically efficient policy is the one that allows for society to derive the largest possible social benefit at the lowest social cost. This occurs when the *net* benefits to society (i.e., total benefits minus total costs) are maximized.

Based on the environmental impact, the marginal environmental gains of add on controls (≈ 24% efficiency), the prohibitive economic cost for add on controls and facility test data from other gas-to-energy facilities in North Carolina, the CO BACT limit for the landfill gas-fired engine/generator unit is:

- Good combustion practices and the New Source Performance Subpart JJJJ limit. Compliance with this CO limit can either be in ppmvd at 15% O_2 or g/hp-hr.

This limit more accurately reflects the quality of the landfill gas at facilities across North Carolina, the test results from facilities in this State and the degradation of engines due to landfill gas contaminants over the life of the engine in between major overhauls. This limit is also the allowable emission rate for all other engines permitted in the State of North Carolina that are not classified as gas-to-energy units.

Best Available Control Technology:
Since the General Statue §62-133.8 (g), Senate Bill 3 – Session Law 2007-397 (State-Enforceable Only) has been in effect, the State of North Carolina has gained a lot of experience and knowledge working with consultants and the landfill gas-to-energy facilities concerning landfill gas contaminants and their effect on pollutant emissions from internal combustion engines.

As found in this analysis, the most cost-effective control of pollutants from landfill gas-fired internal combustion (IC) engines is: good combustion practices with no added pre-combustion or post combustion controls, and the use of design characteristics that are inherent to the lean burn engines. A review of the Federal Register preface and the promulgated regulation for NSPS Subpart JJJJ indicated that no add on controls were used to establish the compliance emission rates for new IC engines. Therefore, the facility's permit will reflect the following:

A. In order to comply with the BACT determination pursuant to GS 62.133.8(g) for each pollutant, the following shall apply:
   1. CO emissions shall not exceed the New Source Performance limits per Subpart JJJJ.
   2. NOx emissions shall not exceed the New Source Performance limits per Subpart JJJJ.
   3. PM10/PM2.5, SO_2, VOCs, Pb, and Hg shall be controlled from each engine using good combustion practices and the burning of landfill gas in the engine.

B. Testing shall be performed according to the requirements of 40 CFR 60.4244 (NSPS Subpart JJJJ) and shall be used to demonstrate compliance with the State BACT limits (NSPS Subpart JJJJ limits).

C. The Permittee shall perform inspections and maintenance as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there are no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:
   1. The Permittee shall perform an annual inspection (for each 12-month period following the initial inspection) to ensure the engine is operating properly.
   2. The results of the inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
      a. The date and time of each recorded action;
      b. The results of each inspection;
      c. The results of any maintenance performed on the engine; and
      d. Any variance from manufacturer's recommendations, if any, and the corrections made.
      e. The Permittee shall maintain a summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping listed above and shall submit the results within 30 days of a written request by the DAQ.

MP Durham burns only LFG in the engines and follows good combustion practices. Prior source testing for NOx and CO, shown in Table 3, demonstrates that MP Durham can comply with these revised State BACT limits. Continued compliance is expected.

8. Other Regulatory Requirements

- A Zoning Consistency Determination is NOT required for this permitting action.
- A P.E. Seal is NOT required for this permitting action.
- The required permit modification application fee of $947 was received by RCO.

9. Emissions Review

Pollutant	Potential Emissions tons/yr
PM (TSP)	4.2
PM_{10}	4.2
$PM_{2.5}$	4.2
SO_2	1.39
NOx	141.5
CO	56.6
VOC	28.3

Historical data regarding the facility's actual emissions can be viewed in this document's header, and are generated using the annual AQEIs as submitted by the facility.

Potential emissions of all pollutants, except for SO_2, from combustion of LFG in the engines were calculated using the following emission factors:

Pollutant	Factor	Units	Source
PM (TSP)	0.15	g/hp-hr	Vendor Guarantee
PM_{10}	0.15	g/hp-hr	Vendor Guarantee
$PM_{2.5}$	0.15	g/hp-hr	Vendor Guarantee
NOx	5.0	g/hp-hr	NSPS Subpart JJJJ
CO	2.0	g/hp-hr	NSPS Subpart JJJJ
VOC	1.0	g/hp-hr	NSPS Subpart JJJJ

Example:

$$\frac{5.0\ grams}{hp-hr} \times \frac{1468\,hp}{engine} \times 2\ engines \times 8760 \frac{hours}{year} \times \frac{2.2\ lb}{1000\,grams} \times \frac{1\ ton}{2000\,lb} = \frac{141.5\ tons\ NOx}{year}$$

To calculate potential SO_2 emissions, AP-42 Chapter 2.4 was used along with information submitted by the facility in the application:

- Engine design rating = 20,755 ft^3/hr per engine (or 1,175.4 m^3/hour total)
- Assume Methane is 50% of this gas stream (587.7 m^3/hour)
- Q_S = Emission rate of reduced sulfur compounds, m^3/hour
- C_S = Concentration of reduced sulfur compounds (46.9 ppmv)
- Multiplication factor for 50% methane concentration in landfill gas = 2.0
- Molecular weight of sulfur = 32.06 g/mole

$$Q_S = 2.0 \times Q_{CH4} \times \left(\frac{C_s}{1 \times 10^6} \right) \qquad \text{(AP-42, Equation 3)}$$

$$Q_S = 2.0 \times 587.7 \frac{m^3}{hour} \times \left(\frac{46.9\ parts}{1 \times 10^6} \right) = \frac{0.055\, m^3}{hour}$$

The mass of the pre-combustion sulfur compounds present in the methane were found using Equation 4 of AP-42, Section 2.4.4.2.:

$$UM_S = \frac{0.055 m^3}{hour} \times \left[\frac{32.06\ g / gmole \times 1\ atm}{\frac{8.205 \times 10^{-5}\ m^3 - atm}{gmol - K} \times \frac{1{,}000\, g}{kg} \times (273 + 25^o C)\ K} \right] \times \frac{2.2\ lbs}{kg} = \frac{0.16\, lbs\,(S)}{hour}$$

To calculate the SO_2 from the combustion of sulfur, Equation 10 of Section 2.4-8 was used.

$$SO_2 = UM_s \times \frac{\eta_{col}}{100} \times 2.0$$

Where:

UM_{cl} = Uncontrolled mass emission sulfur compounds (0.16 lb sulfur/hour)

η_{col} = Collection efficiency of the landfill gas collection system, percent*

2.0 = Ratio of the molecular weight of SO_2 to the molecular weight of Sulfur

* To calculate worst-case SO_2 emissions, the assume that 100% of the generated sulfur compounds are collected and converted to SO_2.

$$SO_2 = 0.16 \frac{lb}{hour} \times \frac{100}{100} \times 2.0 \times 8760 \frac{hours}{year} \times \frac{1\, ton}{2000\, lb} = \frac{1.39\, tons\ SO_2}{year}$$

Additionally, DAQ has recently become aware of significant formaldehyde emissions associated with the combustion of LFG in stationary RICE. As a result, DAQ issued a letter to all facilities with LFG-fired engines on August 19, 2016, requiring the facility to either establish a site-specific emission factor through source testing, or use a generic emission factor of 1.107×10^{-3} pounds of formaldehyde per bhp-hr, developed by the DAQ. Using this emission factor, formaldehyde is now the facility's largest individual HAP emitted, with an uncontrolled potential to emit of 14.2 tons per year, making the facility a major source of HAP emissions as defined in Title III of the Clean Air Act.

10. Air Toxics

The facility was evaluated for toxic air emissions when initially permitted, and acrylonitrile, bromine, chlorine, hydrogen chloride, and hydrogen fluoride were all identified as toxic air pollutants whose emissions exceeded their respective TPERs. The facility conducted modeling to demonstrate compliance with the AAL, the results of which are shown below:

Pollutant	Averaging Period	Emission Rate	Concentration at Property Boundary $\mu g/m^3$	AAL $\mu g/m^3$	% AAL
Acrylonitrile	lb/yr	111.24	0.0056	0.15	3.7%
Bromine	lb/hr	0.096	0.8296	200	0.41%
Chlorine	lb/hr	0.15	1.3229	900	0.15%
	lb/day	3.68	0.5292	37.5	1.4%
Hydrogen Chloride	lb/hr	1.55	13.4152	700	1.9%
Hydrogen Fluoride	lb/hr	0.29	2.5381	250	1.02%
	lb/day	7.05	1.0152	30	3.38%
Vinyl Chloride	lb/yr	152.95	0.0076	0.38	2.0%

As previously stated, in 2016 DAQ became aware of testing which showed significant formaldehyde emissions from engines combusting LFG, including ES-EG3. Using the 1.107 x 10^{-3} lb/bhp-hr emission factor, and the total site rating of the LFG-fired engines, the formaldehyde emission rate was compared to its respective TPER from 15A NCAC 02Q .0711 for obstructed or non-vertically oriented stacks since the stacks have rain caps:

Pollutant	Averaging Period	Maximum Emission Rate	TPER	Modeling Required?
Formaldehyde	lb/hr	4.88	0.04	**YES**

Matt Porter, of DAQ AQAB, conducted a dispersion modeling analysis for formaldehyde emissions from the LFG-fired engines using five years of meteorological data. The facility sits on, and is surrounded by, property owned by Durham County, so a property boundary was conservatively estimated using boundaries of adjoining parcels and proximity of publicly accessible parcels. The dispersion modeling analysis was conducted for three engines since the request to remove ES-EG3 came after the analysis was completed. The following impacts resulted:

Pollutant	Averaging Period	Emission Rate	Concentration at Property Boundary $\mu g/m^3$	AAL $\mu g/m^3$	% AAL
Formaldehyde	lb/hr	4.89	141.4	150	94.2%

Since none of the toxic air pollutants exceed their respective AAL, DAQ has determined that there is NOT an unacceptable risk to human health.

11. Statement of Compliance

MP Durham, LLC was last inspected on June 15, 2018 by Stanley Williams, RRO DAQ. Mr. Williams found the facility to be operating in apparent compliance with their air quality permit at the time of the inspection. The facility was issued a Notice of Violation on March 21, 2014 for late submittal of the Annual Compliance Certification. That violation was resolved on May 21, 2014. There have been no other violations noted in the past five years.

12. Public Notice Review

A notice of the DRAFT Title V Permit shall be made pursuant to 15A NCAC 02Q .0521. The notice will provide for a 30-day comment period, with an opportunity for a public hearing. Consistent with 15A NCAC 02Q .0525, the EPA will have a concurrent 45-day review period. Copies of the public notice shall be sent to persons on the Title V mailing list and EPA. Pursuant to 15A NCAC 02Q .0522, a copy of each permit application, each proposed permit and each final permit pursuant shall be provided to EPA.

The 30-day public notice period was from MONTH XX through MONTH XX, 2018.

The EPA 45-day review period was from MONTH XX through MONTH XX, 2018.

XX comments were received during the public notice and EPA review periods.

13. Comments and Recommendations

The application for permit renewal with modifications for MP Durham, LLC located in Durham, Durham County, NC has been reviewed by DAQ to determine compliance with all procedures and requirements. DAQ has determined that this facility is complying or will achieve compliance, as specified in the permit, with all requirements that are applicable to the affected sources. The DAQ recommends the issuance of Air Permit No. 09971T04.

Attachment 1: Comments and Responses

Comments received from Matt Lamb on August 9, 2018:

Comment 1:
"Please note that the mailing address has changed. The correct address is:

One Grove Street, Suite 301
New Britain, CT 06053"

DAQ Response: The mailing address has been corrected.

Comment 2:
"Please remove from the permit the following source, which is no longer present on site: ES-EG3."

DAQ Response: There was no request to remove the source in the originally submitted permit application. DAQ was aware that the source was previously damaged in a fire and was informed in prior correspondence that the unit may be repaired or replaced. DAQ received confirmation that the facility is now requesting to remove the unit as a permitted source from the Responsible Official, Mr. Steve Laliberty, President of Methane Power, LLC, who stated that "the landfill simply does not have the fuel supply to support three engines." Therefore, ES-EG3 has been removed as a permitted source, and all references to ES-EG3 have been removed throughout the permit.

Comment 3:
"2.1.A.3.d, Testing [15A NCAC 02Q .0508(f)]
'The Permittee shall demonstrate compliance with the emissions standard in Section 2.1 A.3.b above by conducting performance testing in accordance with General Condition JJ and 40 CFR §60.4244. The Permittee shall test one engine every 12-months on a rotating basis such that each engine is tested at least once every three years.'

MP Durham, LLC would like to confirm that stack testing is no longer required to be after 8760 operational hours and is now on a 12-month rotating basis."

DAQ Response: The permit condition cites 40 CFR§ 60.4243(b)(2)(ii), which states, "…you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance." The condition quoted by Mr. Lamb was intended as a clarification that the facility has previously been granted permission by DAQ to test one engine as representative of the others, as long as the engines are tested on a rotating basis such that each engine is tested within the 3-year timeframe required by 40 CFR §60.4243(b)(2)(ii). DAQ agrees that this statement is potentially confusing and can be misinterpreted, therefore, the condition has been changed to reflect the requirements as they appeared in the previous permit revision, and as they appear directly in 40 CFR §60.4243(b)(2)(ii). MP Durham, LLC may still conduct representative performance testing as allowed by determinations issued to the facility by DAQ.

Comment 4:
"2.1.a.4.d, Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]
'The Permittee shall monitor and record the daily fuel usage (i.e., the amount of landfill gas burned) for each engine. [40 CFR §63.6625(c)]'

MP Durham, LLC currently monitors landfill gas flow at the header prior to distribution to the separate engines. Flow is not measured individually at each individual engine. The facility only receives gas from the landfill and does not have multiple gas sources to meter.

This is consistent with 40 CFR §63.6625(c), which states:
'If you are operating a new or reconstructed RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to ***measure the volumetric flow rate of each fuel.****'*

It is clear that the rule requires separate flow meters for each fuel, in order to determine the percent of landfill gas fired in the RICE unit relative to other fuel types on an annual basis. MP Durham, LLC fires only landfill gas in ES-EG1 and ES-EG2. No other fuel types are present at the facility. Therefore, no other flow meters are required to measure fuels other than landfill gas. Please clarify that it is not the intent of this condition to require metering of separate flow to each individual engine."

DAQ Response: DAQ agrees with the statement that the rule requires separate flow meters for each fuel, in order to determine the percent of landfill gas fired in the RICE unit relative to other fuels on an annual basis. However, the MACT applies to each affected source individually, and the permit condition as written is consistent with permit conditions written for other similar facilities. DAQ believes that MP Durham, LLC can comply with the requirement to monitor and keep records of each engine's fuel consumption individually without requiring the installation of separate flow meters. For example, the facility can possibly determine the fraction of the total fuel usage for each engine based power generation or may use other methods acceptable to DAQ to demonstrate compliance.

Comment 5:
"2.1A.4.e, Reporting [15A NCAC 02Q .0508(f)]
'The Permittee shall submit an annual report by January 30 of each calendar year for the previous 12-month period ending December 31. The report shall include:
i. the annual and daily maximum flow rates and the heating values of each fuel fired in each engine;'

As stated above, MP Durham, LLC monitors landfill gas at the header prior to the engines. Additionally, methane concentration is monitored weekly via portable hand-held meter. Please clarify that it is not the intent of this condition to require continuous methane monitoring of separate flow to each engine."

DAQ Response: See the previous response regarding fuel flow monitoring for each engine. The requirement to report the heating values of each fuel comes directly from the reporting requirement in 40 CFR §63.6650(g)(1). The heating values are to be used to demonstrate that the affected sources are indeed firing LFG for at least 10% of the total fuel consumption on an annual basis. DAQ believes that, given MP Durham, LLC's current practices of only combusting LFG, the practice of weekly monitoring of methane concentration is sufficient to demonstrate compliance, therefore, more frequent or continuous methane concentration monitoring is not required in this case.